LA-UR-78-2625

CONF-781209--1

MASTER

TITLE: SIMULATION AND OPTIMIZATION OF HOT DRY ROCK GEOTHERMAL ENERGY CONVERSION SYSTEMS: PROCESS CONDITIONS AND ECONOMICS

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SUBMITTED TO: Proceedings of the International Symposium on Systems Optimization and Analysis
December 11-15, 1978
Paris, France

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DEPARTMENT OF ENERGY
CONTRACT W-7405-ENG. 36

SIMULATION AND OPTIMIZATION OF HOT DRY ROCK GEOTHERMAL ENERGY CONVERSION SYSTEMS: PROCESS CONDITIONS AND ECONOMICS

by

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ABSTRACT

The Los Alamos Scientific Laboratory is currently engaged in a field program aimed at designing and testing man-made geothermal reservoirs in hot granitic formations of low permeability created by hydraulic fracturing. A very important segment of the program is concerned with defining and optimizing several parameters related to the performance of the reservoir and their impact on the potential commercial feasibility of the hot dry rock technique. These include effective heat transfer area, permeation water loss, depth to the reservoir, geothermal temperature gradient, reservoir temperature, mass flow rate, and geochemistry. In addition, the optimization of the energy end use system (process or district heating, electricity, or cogeneration) is directly linked to reservoir performance and associated costs. This problem has been studied using several computer modeling approaches to identify the sensitivity of the cost of power to reservoir and generation plant parameters. Also examined were a variety of important economic elements including rate of return on invested capital, discount or interest rates, taxes, cash flow, energy selling price, plant and reservoir lifetime, drilling and surface plant costs, and royalties.

INTRODUCTION AND SCOPE

This paper will review the simulation and optimization of generic hot dry rock geothermal energy systems as they are currently characterized by the ongoing research and development project at the Los Alamos Scientific Laboratory supported by the Division of Geothermal Energy of the U.S. Department of Energy (Smith, 1975, Tester and Smith, 1977, Blair, 1978, Tester, to be published). Because of space and time constraints, it will not be possible to elaborate on details of the physical and mathematical models used; but basic concepts, important constraints, and major implications of the results will be summarized. Direct practical applications of simulation and optimization procedures occur in two main project areas: (1) economic feasibility analysis and (2) design and interpretation of field experiments. In the first case, optimization techniques are used to develop economic strategies for determining what set or sets of conditions are required for commercial feasibility of electricity and/or process heat production from hot dry rock (Blair, 1978). In the second case, efforts have concentrated on the development of models to describe heat transfer, fluid flow, and chemical interaction between rock and water as observed in field tests of actual hot dry rock reservoirs.

HOT DRY ROCK SYSTEMS

To provide a background for understanding simulation and optimization problems related to hot dry rock geothermal energy utilization, several technical aspects of the reservoir and surface systems are described. Presently operating geothermal power plants throughout the world typically involve an underground reservoir containing natural steam and/or hot water which is brought to the surface via a set of drilled wells. Geothermal fluid flows under artesian pressure or is pumped through a collection system of pipes to a centrally located power plant which may produce electricity, process heat, or both. Often reinjection wells are used to return the cooled fluid to the formation. The main feature that distinguishes these natural hydrothermal systems from a hot dry rock (HDR) reservoir is the absence in the HDR case of a sufficient amount of spontaneously-produced indigenous fluid to be considered economically or for that matter practically productive.

This impor' + feature of the HDR resource provides a degree of flexibility that is in absent from natural hydrothermal reservoirs. Namely that HDR reservoir tem 'res may be selected by drilling to a specified depth determined by the geot l temperature gradient. In the case of a short reservoir lifetime, remedial tment of an HDR reservoir is also possible by redrilling to a hotter region of rock. In the hydrothermal case, the reservoir conditions, including in situ fluid temperature, pressure and composition, and formation permeability and porosity, are determined a priori by prevailing natural conditions in that region. Thus, this unique relationship between reservoir temperature and depth in the HDR case provides a framework for exploring the economic dimensions of deeper, hotter, more costly wells versus shallower, cooler, less expensive wells balanced against the price of the produced product, electricity and/or heat.

HDR reservoirs may exist in formations having permeabilities ranging from very low (<1 μdarcy) to high (>10 millidarcy) where the rock itself is hot enough to be considered useful for energy extraction. Depending on end-use, this may be as low as 100°C for space heating purposes or higher than 300°C for producing electricity. In all cases an HDR formation requires artificial stimulation to create either sufficient in situ permeability or bounded flow paths to allow removal of heat by circulation of a suitable fluid over the surfaces of the rock.

Reasonable rates of energy extraction and sufficient reservoir lifetimes (∿20 yr or greater) from HDR systems may be achieved using two fundamental approaches to mining the heat. First, if in situ formation permeabilities are low, an artificial system must be created to expose a circulating fluid (e.g. water) to hot rock by creating high conductance flow passages with a sufficiently large heat-transfer surface area. In this case, recovery of most of the injected fluid may be achieved quite easily by taking advantage of the natural containment provided by the low formation permeability (Smith, 1975, Tester and Smith, 1977). Second, if permeabilities are high, the problem of fluid circulation is probably not as demanding as containment and recovery of the fluid and insuring uniform fluid contact with the hot rock surface. Approaches used for recovery of gas and oil by water-drive or flooding methods may be quite applicable. Both production- and injection-well networks would be arranged in a manner to minimize fluid loss to surrounding permeable formations at the perimeter of the developed geothermal field.

One concept applicable to low permeability formations being considered by the Los Alamos Scientific Laboratory is depicted in Figure 1 (Smith, 1975, Tester and Smith, 1977, Blair, 1978, Tester, to be published). In this case, a single vertical hydraulic fracture is produced from one wellbore by fluid pressurization sufficient to exceed the confined strength of the rock. Required surface areas for heat extraction are created by continued high pressure injection of fluid. The downhole system is completed by directionally drilling a second wellbore to intersect the fractured region with sufficient separation from the first wellbore to avoid flow short-circuiting. Pressurized working fluid is then circulated down one hole through the fractured region to remove energy from the rock, and recovered in a second hole. Energy is extracted at the surface using heat exchangers and the cooled fluid reinjected to complete a closed cycle. Even with low permeabilities, some makeup water is required. Because reservoirs of this type will most likely be formed at depths sufficient to insure that the least principal earth stress is in the horizontal plane, the hydraulic fracture should have a near vertical orientation; and assuming that the stress field is uniform and the physical strength properties of the formation are approximately isotropic and homogeneous, an ideal fracture of circular shape with elliptical cross-section should be formed (Smith, 1975, Tester and Smith, 1977, McFarland and Murphy, 1976, Harlow and Pracht, 1972, Raleigh, 1974). Fracture radii will be typically 100 m or greater with widths of a few millimeters in cross-section. Because the inherently low thermal conductivity of the rock quickly controls the

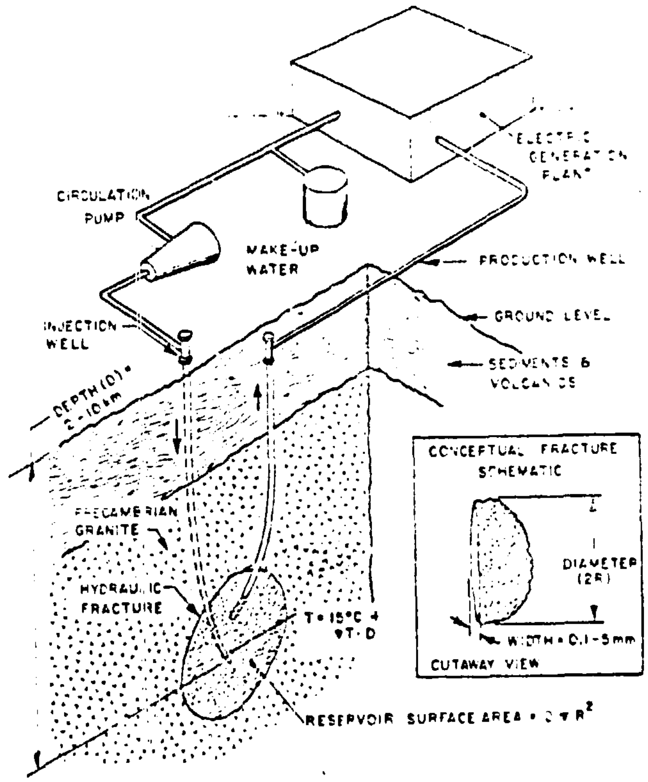

Fig. 1 Hot Dry Rock conceptual system for low permeability formations.

rate of heat transfer to the circulating fluid, large fracture surface areas are required. In order to optimize the performance of a reservoir of this type, fluid should contact as much of the fracture surface as possible. Fracture conductances or permeabilities for self- or pressure-propped fractures should be sufficiently high to permit buoyant circulation across the faces of the fracture between the inlet and outlet points of the system as shown in Figure 1.

The changes that may occur in the reservoir output fluid temperature as well as the rate of power production over the 20-40 year lifetime of an HDR power plant can be crucial in developing an optimal strategy for reservoir management. The most desirable approach is to maintain a constant output temperature while maximizing the mass flow rate of fluid through the reservoir. This will not be possible because any finite sized system will have a finite rate of drawdown. The energy drawdown rate for a fractured HDR reservoir with low formation permeability will depend on:

(1) accessible fracture surface area, $A = \pi R^2$ (R-fracture radius)
(2) mass flow rate, $\dot{m}_w$
(3) distribution of fluid across the fractured surface
(4) thermal properties of the rock (density, heat capacity, conductivity)

A simplified approach to estimating reservoir performance would assume that a certain fraction, η, of the recoverable power, corresponding to uniform flow across the face of an ideal plane fracture, could be extracted. By solving the transient problem of one-dimensional, heat conduction from the rock into the fracture face, the recoverable power, P(t) in J/sec, for uniform flow can be expressed as shown in Figure 2 where the parametric dependence of the thermal power ratio $(P(t)/P(t=0))$ on the mass loading parameter $\dot{m}_w/R^2$ is presented.

For cases where large stable fractures cannot be produced, smaller multiple parallel fractures may be used to generate the required surface area to maintain an acceptable reservoir lifetime. Gringarten et al (Gringarten, 1975) and Wunder and Murphy (Wunder and Murphy, 1978) have examined the heat extraction capacity of multiply fractured systems showing the effects of variable fracture number and spacing. Because of the low thermal conductivity of granite, the penetration depth of the thermal wave is small; and fractures spaced 20-50 meters apart avoid thermal interference over a 20-30 year period. Thus the thermal drawdown will resemble that for a single fracture as shown in Figure 2. Figure 3 shows how a particular multiple, parallel fracture system might be designed between a pair of parallel inclined wellbores separated by a vertical distance d to achieve 50% thermal drawdown in 20 years.

ELECTRIC POWER GENERATION FROM HOT DRY ROCK SYSTEMS

Using a geothermal resource to supply heat to an electric power generating cycle frequently involves a different set of design criteria than conventional fossil-fuel fired or nuclear generating cycles (Milora and Tester, 1976). Because conversion efficiencies range from 8 to 20% for geothermal resource temperatures of 100 to 300°C, and because drilling-related costs frequently represent more than 60% of the total capital investment in the power plant, a premium is placed on designing and operating conversion systems near their thermodynamic limiting efficiencies. The following discussion summarizes the main features of a study of geothermal power conversion systems made by Milora and Tester (Milora and Tester, 1976) where the main effort was directed toward developing thermodynamic and economic design criteria applicable to optimizing the generation of electric power from low-temperature geothermal resources.

Rankine or similar cycles have been used for power production with water as the working fluid, particularly where natural steam is available. For liquid-dominated systems, steam vapor can be created by flashing the geothermal fluid at the surface to a lower pressure. Then, the saturated steam phase can be used to drive a turbogenerator unit, with the unflashed liquid fraction either reinjected or discarded. Binary-fluid cycles employing non-aqueous working fluids are alternatives to single- and multiple-flashing systems currently in use in various parts of the world (for example Cerro Prieto, Mexico and Wairakei, New Zealand (Kruger, 1973)). Binary-fluid cycles involve a primary heat exchange step where heat from the geothermal fluid is transferred to another working fluid which expands through a turbogenerator and then passes to a condenser/desuperheater for heat rejection to the environment. The cycle is completed by pumping the fluid up to the maximum cycle operating pressure.

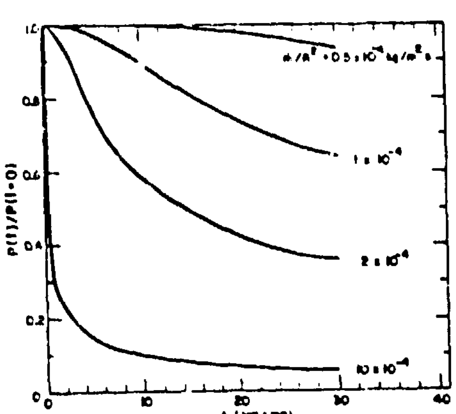

Fig. 2. Parametric power drawdown curves for a single fracture with no thermal stress cracking, n=0.9.

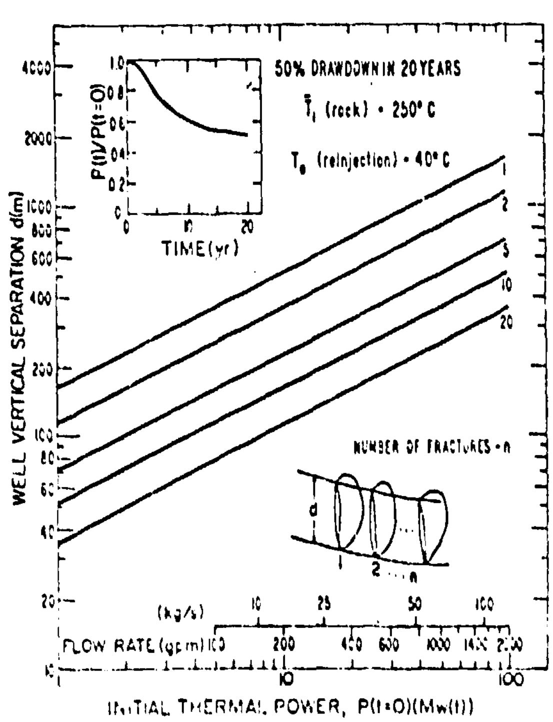

Fig. 3 Required vertical well separation as a function of the initial thermal power and number of frac-

Non-aqueous working fluids with large, low-temperature vapor densities would require smaller turbines than the low-pressure steam turbines employed in flashing systems of the same power output. This is particularly true where heat rejection conditions of 30°C or less exist. Flashing cycles are, of course, simpler in that they do not require a primary heat exchanger.

Seven working fluids in addition to water were examined. Refrigerants, R-22 ($CHClF_2$), R-600a (isobutane, i-C_4H_{10}), R-32 (CH_2F_2), R-717 (ammonia, NH_3), RC-318 (C_4F_8), R-114 ($C_2Cl_2F_4$) and R-115 (C_2ClF_5) were selected because they provided a range of critical temperatures and pressures, and molecular weights. All of these compounds have relatively high vapor densities compared to water at temperatures as low as 20°C.

Detailed calculations of binary-fluid Rankine cycle configurations were performed to examine the effects of cycle operating pressure, heat rejection temperature, temperature differences in the primary heat exchanger and condenser, turbine and pump efficiencies, and fluid temperature. In each case a utilization efficiency η_u was determined which related the actual electrical work produced by the cycle to the maximum work (or availability) possible with specified geothermal source and heat rejection temperatures. Comparisons were also made with single and multistage steam flashing cycles.

For any given working fluid, there is an optimum set of operating conditions yielding a maximum η_u for particular geothermal fluid and heat rejection temperatures and turbine and pump efficiencies. In screening potential working fluids, some knowledge of the magnitude of η_u and how it changes would be useful. Computer optimizations for the seven working fluids studied were conducted for geothermal fluid temperatures ranging from 100 to 300°C. In each case, cycle pressures were varied until an optimum was determined at that temperature. One observes a characteristic maximum η_u at a particular resource temperature which is different for each fluid but generally in the range of 60 to 70%; assuming a minimum approach (pinch point) temperature of 10°C between the countercurrently flowing geothermal and cycle working fluids in the primary heat exchanger, an 85% dry turbine stage efficiency, and an 80% feed pump efficiency. Component efficiencies of this magnitude have been achieved in similar sized commercial units (Milora and Tester, 1976). The thermodynamic code for cycle analysis was used in estimating surface conversion plant costs.

Several engineering issues related to the reservoir and the surface conversion plant influence costs:

(1) reservoir lifetime and size
(2) reservoir flow capacity
(3) heat rejection conditions
(4) plant design temperature
(5) pressure losses and pumping requirements
(6) geothermal fluid chemistry.

Topics (1)-(4) reflect directly on reservoir and plant performance discussed earlier. For example, fracture size (A) and system flow capacity ($\dot{m}_w$) attainable will depend on success in developing operational reservoirs for a wide variety of in situ conditions. These reservoirs may encompass formation of large fractures, multiple parallel fractures, remedial refracturing and thermal stress cracking enhancement (Tester and Smith, 1977). Consequently, in order to examine the impact of finite reservoir size and flow capacity, thermal drawdown rates are established for specified reservoir conditions using equations presented in the reservoir performance section. For any given set of resource and power plant conditions, Milora and Tester (Milora and Tester, 1976) were able to show that an optimal plant design temperature exists. The selection of the optimum becomes more complex as reservoir temperature declines. One reason for this is the severe cycle performance penalty experienced by operating the plant at below design conditions. The primary effect of a reduced wellhead or reservoir temperature is a reduction in cycle and utilization efficiency.

If a conventional steam flashing cycle were used, it would be very difficult to economically extract work from the turbine at an exhaust temperature approaching 27°C because the density of saturated steam ...

that extremely large turbine blade areas would be required. Nonetheless, in many parts of the U.S. it may not be possible to operate at these low heat rejection temperatures. For example, in the Imperial Valley area of California 49°C (120° F) is a more appropriate design condensing temperature. For these cases, the advantage of non-aqueous, high vapor density working fluids in binary cycles over steam flashing cycles is diminished. Another point concerning heat rejection has to do with the effect of seasonal and diurnal variations in ambient temperature on cycle performance. Conventional practice in the power generation industry is to design the plant capacity for the "worst" day conditions. Because of the smaller size of geothermal units (<100 MW(e)), it might be desirable to operate with a floating power output. In addition, because of the inherently low efficiency of geothermal cycles in general when operating with pressurized water below 300°C, a premium is placed on optimizing cycle performance by utilizing lower ambient temperatures when and where environmental conditions permit. For example, with 200°C liquid resource a decrease in condensing temperature from 49° to 27°C increases the potentially available work by as much as 40% (Milora and Tester, 1976).

A preliminary estimate of the geothermal fluid flow requirements is given in Figure 4 for thermodynamically optimized binary fluid cycles operating with a 10°C approach temperature in the primary heat exchanger and condenser and a 27°C condensing temperature.

Pressure losses throughout the system will affect pumping requirements and therefore costs. These will include frictional losses in piping, well casing, within the fracture itself and form drag losses at the entrance and exit regions of the fracture in each wellbore (Blair, 1978). These losses are partly offset by the buoyancy gain between the cold injection and hot recovery wellbores. The impedance within the fracture system and at the exit and entrance regions will probably have the largest impact since it may be partially controlled by formation properties and fracture system geometry as we have seen at the LASL Fenton Hill test site (Smith, 1975, Blair, 1978, and Tester, to be published). Frictional losses in the surface and downhole piping can, of course, be minimized by increasing diameters.

In some cases the chemical composition of the geothermal fluid may strongly influence the cost of surface and subsurface components. As reservoir temperatures increase by drilling deeper, general increases in mineral solubility and reaction rates are observed. Consequently the potential for corrosion and particularly silica and carbonate scaling will increase as rock-water temperatures rise. However, this effect will be site and formation specific and its economic impact evaluated separately in each case.

ECONOMIC CONSIDERATIONS

A complete evaluation of HDR technology as it relates to electricity production must necessarily overlay cost accounting and financial features upon the resource and engineering dimensions noted above. These include capital and operating costs, revenues, interest rates, taxes and other financial issues. An intertemporal dynamic programming computer model with a discounted cash flow approach was used to determine the optional management strategy for an HDR system and to evaluate its commercial attractiveness. The model addresses both of these issues because an HDR system has a number of important design and operating choices which can be selected to optimize return on investment. The correct basis for evaluating the commercial potential of an HDR system, then, is closely related to the optimal design and management of that system. Surface plant construction capital costs were adapted from Milora and Tester (Milora and Tester, 1976). These costs are estimated to be a decreasing function of design temperature between 100 and 300°C and directly proportional to capacity (above 50 MW(e)) as shown in Figure 5.

Although the calculational methods concerning the details of how the results of Figure 5 were empirically developed cannot be presented here because of space limitations, several important features are described. First, a fact[illegible]ed

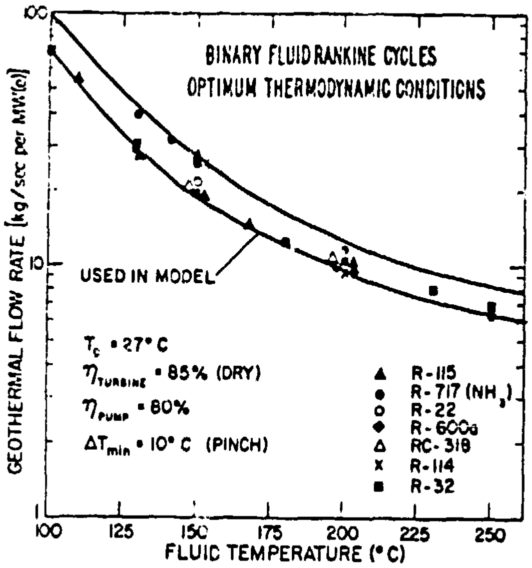

Fig. 4 Geothermal fluid flow rate requirements as a function of wellhead fluid temperature for optimized conversion cycles for seven different working fluids.

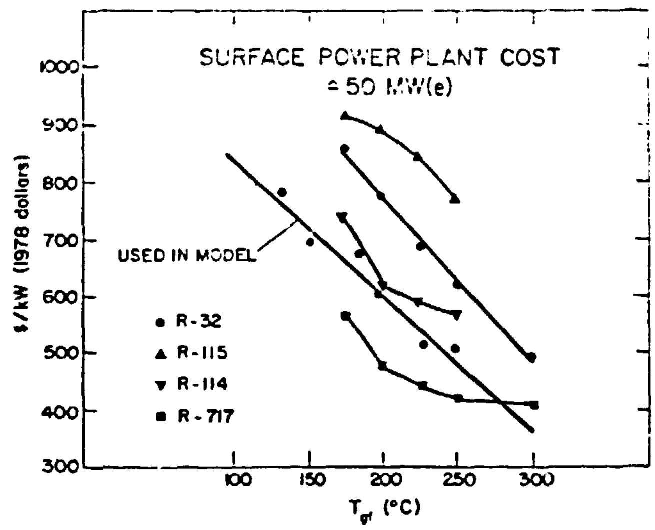

Fig. 5 Optimized surface plant capital costs as a function of geothermal fluid temperature for four different working fluids.

estimate approach was used where direct and indirect cost multiplying factors were combined with the total purchased cost of major equipment associated with power conversion to arrive at an estimate of the fixed capital investment. For the binary fluid cycles considered, this equipment included a primary heat exchanger, desuperheater/condenser, wet or dry cooling towers, turbine, generator, and feed pump. The direct cost factor covers the costs of plant piping, buildings and structures, instrumentation, equipment installation and the indirect factor, engineering fees, contingency, escalation during construction, and environmental impact. The application of these cost factors resulted in the installed cost of the surface plant to be 2.8 times the purchased cost of the major equipment. Plant capacities in the 50 to 100 MW(e) range were used. Heat exchange equipment was costed using empirical correlations which gave component cost per unit surface area as a function of material of construction, and shell and tube side pressures. Turbine and pump costs were also generated empirically based on such things as number of stages, exhaust end pitch diameter, casing pressure, blade tip speed, and materials of construction (Milora and Tester, 1976). For each fluid a number of heat rejection temperatures (27, 37, 49°C) and designs were also pursued, these included dry and wet cooling towers, direct air cooled desuperheater/condensers and once through fresh and sea water condensers. Plant operating conditions were optimized to minimize combined surface plant and reservoir development investment costs. Parameters that were varied included, primary heat exchanger and condenser approach temperatures and cycle operating pressure from subcritical to supercritical operation (Milora and Tester, 1976).

The power plant costs were then distributed over an estimated five-year construction period: ten percent cash outlay in the first year, seventeen percent in the second year and 24.33 percent in the third, fourth and fifth years of construction. In keeping with the conceptual framework of the commercial feasibility criterion, these staggered construction costs were all compounded by the appropriate discount rate to the beginning of plant operations (year 0).

To these surface plant costs, costs related to site leasing and development, property or ad valorem taxes and working capital charges were added. In addition, drilling costs were added which were comprised of drill rig mobilization-demobilization charges, daily rig rental charges, completion and casing costs, fluid gathering system capital costs, and materials and services costs. In general, the drilling charges included a fixed fee plus a term exponentially dependent on the depth and proportional to the number of well pairs drilled and completed (Milora and Tester, 1976). The cost of the piping and equipment for the fluid gathering system is calculated as directly proportional to the linear footage required to make piping connections among the corners of an array of equilateral triangles.

Income taxes are also included to tax equity returns on capital at a combined state-federal income tax rate of 51%. In addition, 51% of interest payments necessary to finance corporate debt are subtracted from the gross income to compute taxable income. Two discount rates r and i are selected for use in the model. The discount rate r is meant to represent the real, after tax, opportunity cost of capital to the firm. This might be thought of as the minimum equity rate of return. The debt rate of return, i, is meant to represent the cost of borrowing the debt portion of the capital investment. For convenience it is assumed that the surface plant costs are 100 percent debt financed and the drilling costs are 100 percent equity financed. For an integrated investment, this corresponds to approximately a 0.5 debt/equity ratio. Discounted revenues were computed as the product of average minimal electricity production in kWh and the adjusted busbar selling price in $/kWh.

In general, public utilities are currently paying a nominal debt interest rate of approximately nine percent and a nominal equity rate of return of approximately twelve percent. By assuming that these investors anticipated a general future rise in prices of six percent a year, one can deduce that the real rates of return required by these investors were three and six percent. These rates were selected for the base case runs of the model with the higher equity rate of return applied to drilling costs and the lower debt interest rate to power generation costs.

ECONOMIC OPTIMIZATION EXAMPLES

The major function of the optimization model is to evaluate how the present value of net (after-tax) profits for an HDR electric-generating facility vary with the geothermal temperature gradient, ∇T, and the design well-flow rate, $\dot{m}_d$, for a specified busbar electricity price. Typical results showing the effects of gradient and flow rate are shown in Figure 6 assuming uniform production for a 30-year period and a busbar price of 4¢/kWh (1978 dollars).

Given values for ∇T, $\dot{m}_d$, and the price of electricity at the beginning of each decision period (a "decision period" in this case is a five-year time-interval) the model calculates the present value of present and future profits associated with all combinations of $\dot{m}$ and drilling (and redrillings) depths, and chooses the combination which maximizes the profits. Given that all costs, taxes, insurance, and accumulated interest charges are included in the model, a <u>zero</u> value for the objective function implies a breakeven <u>cost</u> of 4¢/kWh. A negative value for the objective function would imply a breakeven cost greater than 4¢/kWh and a positive value would imply a breakeven cost less than 4¢/kWh. A complete specification of this dynamic programming model is given by Cummings, et al (Cummings, 1977). The issue of what busbar price is required to reach economic feasibility is certainly an important one. Because of the mathematical structure of the model, however, it must be determined indirectly. In the intertemporal model the busbar price of electricity, p, is specified as a parameter, as are geothermal gradient ∇T and design flow rate $\dot{m}_d$ before the dynamic programming algorithm begins computation. When the net profits or benefits equals zero, this breakeven point is reached for a given set of conditions including price, $(p=p^*)$. p^* is therefore referred to as the "breakeven" price. At this point, the revenues produced from the sale of electricity are enough to just cover all costs, including interest payments of debt, return on equity and income and ad valorem taxes, where both the revenues and costs are evaluated in terms of present discounted value. Results are presented in Figure 7 for base case conditions where p^* is shown as a function of temperature gradient with a design fluid temperature T_d of 160°C and a thermal drawdown rate corresponding to $\dot{m}/R^2 = 1.389 \times 10^{-4}$ kg/m^2-s.

SIMULATION OF PROCESS CONDITIONS

Several properties of the field reservoir have been modeled and are briefly outlined here (for details see Tester and Smith, 1977). First, as mentioned earlier heat transfer analysis of fluid-filled reservoirs has been studied in detail by Murphy and McFarland (Blair, 1978 and McFarland and Murphy, 1976). Fluid buoyancy and convection effects within an ideal fracture as well as transient condition of heat through the surrounding rock are treated in a numerical solution of the four coupled, two-dimensional, non-linear partial differential equations describing continuity, fluid momentum, and rock and fluid energy balances. This model has been used to empirically simulate the observed thermal drawdown of a prototype hot dry rock reservoir recently tested in the field at Fenton Hill, New Mexico (Tester, to be published). Results are shown in Figure 8 for a 75-day test of that reservoir.

Fisher (Fisher, 1977) has also been able to use a one-dimensional, transient fluid diffusion model with pressure dependent and anisotropic permeability and pressure dependent porosity and compressibility to simulate fluid permeation during that same 75-day test as shown in Figure 9.

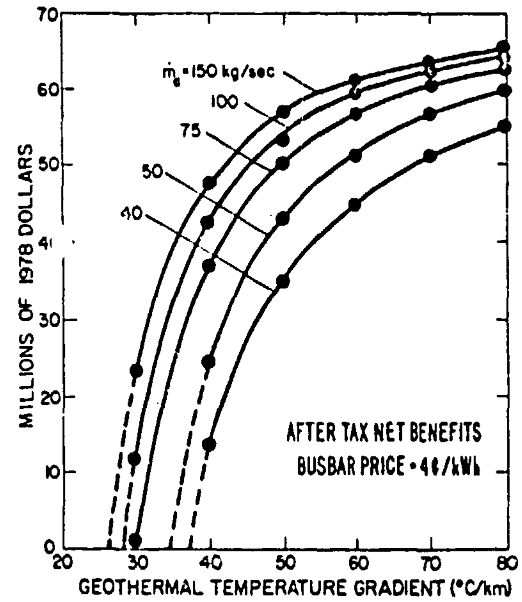

Fig. 6 Intertemporal optimization model results with a present value busbar price of 4¢/kWh, after tax net benefits or profits shown as a function of geothermal gradient and flow rate.

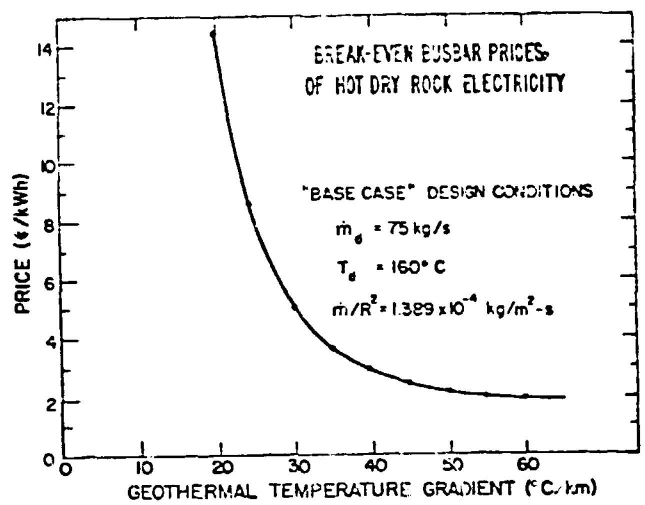

Fig. 7 Busbar price for breakeven economic feasibility conditions at base case conditions.

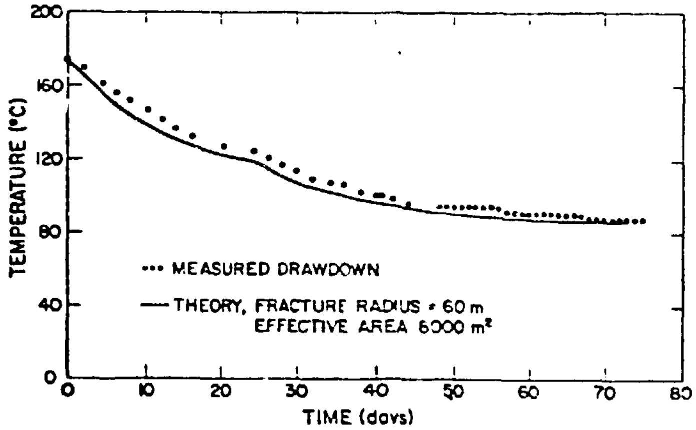

Fig. 8 Measured and predicted thermal drawdown during a 75-day test (Feb. to April, 1978) of the prototype hot dry rock reservoir located at Fenton Hill, New Mexico.

Tester (Tester, to be published) in a third study of fluid residence time distribution in the Fenton Hill reservoir was able to simulate the behavior of injected tracer using a composite model to superimpose flow with dispersion through separate zones of the reservoir. The results of a five-zone fit to the observed residence time distribution are presented in Figure 10.

ACKNOWLEDGEMENT

The author would like to thank R. Cummings, G. Morris, R. L. Bivins, H. Fisher, and H. Murphy for their personal contributions to developing simulation and optimization techniques applicable to Hot Dry Rock Systems. Without their efforts it would not have been possible to write this paper. Doris Elsner is also thanked for her assistance in preparing the manuscript for publication.

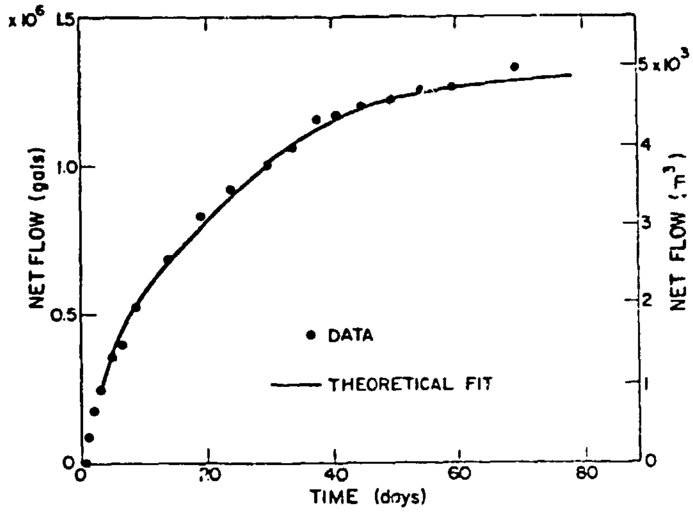

Fig. 9 Measured and predicted total water permeation for the 75-day test (Feb. to April, 1978) of the Fenton Hill reservoir.

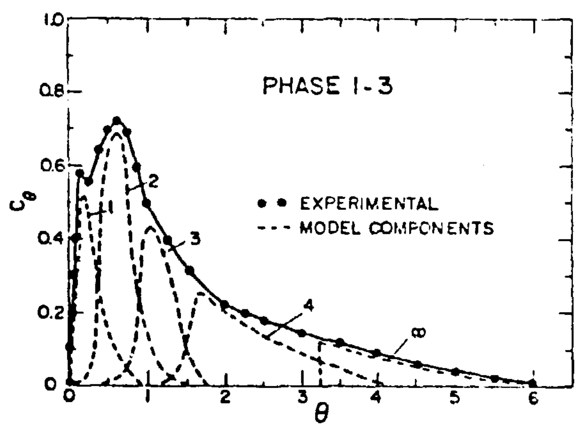

Fig. 10 Experimental and predicted dye tracer results with normalized dye concentration C_θ shown as a function of normalized residence time $\theta = t/\bar{t}$ for a response to a pulse input during the 75-day test (Feb. to April, 1978) of the Fenton Hill reservoir.

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